Maine Public Utilities Commission

Annual Report on Electric Restructuring

December 31, 2001

Annual Report on Electric Restructuring

Report to the Utilities and Energy Committee
On Actions Taken by the commission Pursuant to 35-A M.R.S.A. § 3217

I. BACKGROUND

During its 1997 session, the Legislature enacted comprehensive legislation to restructure Maine's electric utility industry. P.L. 1997, ch. 306 (codified at 35-A M.R.S.A. §§ 3201-3217). This law has remained virtually intact since its enactment, and has thus provided a stable operating environment for companies and customers affected by electric restructuring.

During 1998 and 1999, the Public Utilities Commission (Commission or Maine PUC) used rulemaking procedures and stakeholder groups to develop the rules and procedures that would govern the activities of T&D utilities and competitive electricity providers after restructuring occurred. In addition, we conducted a consumer education campaign to prepare customers for restructuring. Finally, we disaggregated the existing vertically integrated utilities into their delivery and generation functions, determined rates for the future T&D utilities, and approved the sale or auction of Maine's generating facilities. Because of the comprehensive preparation, entities operating in Maine avoided some of the technical and procedural problems encountered in many other states.

During 2000, we guided the implementation of restructuring rules and procedures following the onset of restructuring on March 1, 2000. We monitored and revised the standard offer selection process and licensed, monitored and advised competitive electricity providers. Finally, we significantly increased our participation in regional wholesale market and transmission activities, as it became apparent that regional and national activities significantly influenced the price of electricity for Maine's consumers.

During 2001, we have continued to work to implement restructuring consistent with the legislation. Our primary focus has been to promote a healthy competitive retail electricity marketplace in which consumers can exercise choice and receive electricity at the lowest possible rates. In doing so, we increased our regional participation, further refined the standard offer bidding process, and helped competitive electricity providers operate in Maine by offering guidance and maintaining a stable, reliable regulatory environment.

35-A M.R.S.A. § 3217(1) states in part:

> 1. **Annual restructuring report.** On December 31st of each calendar year, the commission shall submit to the joint standing committee of the Legislature having jurisdiction over utility matters a report describing the commission's

activities in carrying out the requirements of this chapter and the activities relating to changes in the regulation of electric utilities in other states.

This report describes our activities during calendar year 2001.

II. RETAIL MARKET ACTIVITY – YEAR 2

After almost two years of operation, Maine's retail market continues to gain strength. All generation prices are determined by competitive market procedures, as Maine's restructuring law envisioned. The number of customers who have migrated from the standard offer to an open market supplier far outstrips migration in any other state. There is a modest diversity of retail suppliers for commercial and industrial customers, while residential and small commercial customers have the benefit of vigorous competition among standard offer bidders. Wholesale energy prices have recently decreased. For residential customers and for non-residential customers who are willing to shop for generation, all-in electric prices are generally lower than or comparable to prices before restructuring. The business operations among retail entities (utilities, suppliers, and customers) are efficient and effective. The development of regional market rules has been fraught with discord, but there appears to be some progress toward an efficient market. No "green" market has developed, but suppliers have observed the mandated 30% portfolio requirement. Finally, no retail market for residential customers has yet developed. In the following paragraphs, we will discuss these features of Maine's market in more detail.

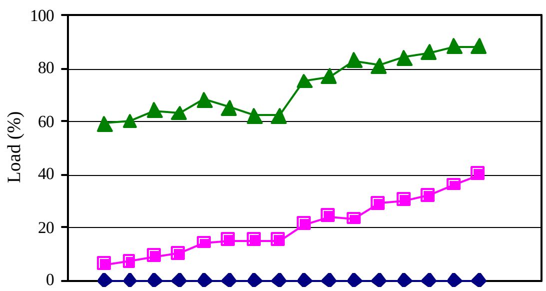
As anticipated, migration to open market suppliers began with the state's largest customers and is extending to smaller customers over time. At the beginning of 2001, the majority of large industrial customers were purchasing power from an open market supplier, but most medium customers still purchased standard offer service.[1] Calendar year 2001 saw a significant increase in migration among the medium customers. By the end of 2001, almost half of the medium customer load had migrated, as well as additional large customer load.[2] The migration of medium customers accelerated during the summer of 2001, when energy prices decreased substantially below standard

[1] A "large" customer has a load of 500 kW or greater, or 400 kW or greater in Central Maine Power Company's (CMP) territory. A "small" customer has a load of 20 kW, 25 kW, or 50 kW or less in CMP's, Bangor Hydro-Electric's (BHE), and Maine Public Service Company's (MPS) territories respectively. A "medium" customer is one with load between the small and large categories. Large customers include paper manufacturers, the largest colleges and hospitals, and the largest super markets. Medium customers include smaller industrial plants, the majority of colleges and hospitals, grocery stores, and large office buildings.

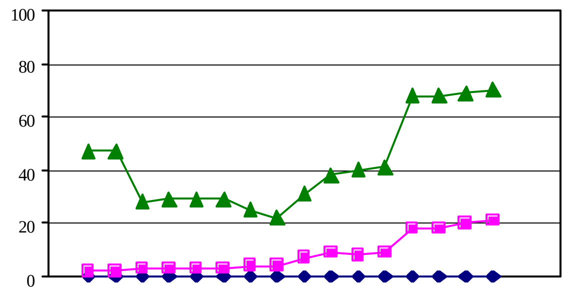
[2] MPS migration statistics differ significantly from CMP's and BHE's. In MPS territory, there are fewer suppliers offering generation service. However, far more customers migrated to those suppliers early in the restructuring process, and a far higher percentage of residential and small customers have migrated.

offer rates and remained relative stable. Migration rates are shown in the charts below. For comparison, migration rates in other states are shown in Appendix A.

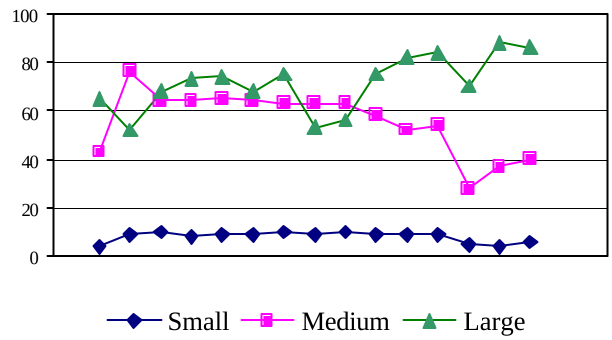
Central Maine Power



Bangor Hydro



Maine Public Service



Percentage of kWhs Served by Competitive Suppliers, December 2001

	CMP	BHE	MPS
Residential/ Small	<1%	<1%	7%
Medium	42%	22%	56%
Large	88%	73%	89%
All Maine Customers	48%	26%	41%

Total State Percentage: 44%

Number of Customers Served by Competitive Suppliers, December 2001

	CMP	BHE	MPS
Residential/ Small	161	133	1281
Medium	2908	225	130
Large	238	18	14
Total	3307	376	1425

This high level of migration can in part be attributed to a sharp increase and subsequent decline in generation market prices. In fall 2000, natural gas prices rose to historically high levels. This price spike was reflected in the prices electric suppliers bid for standard offer service. When natural gas prices and generation market prices subsequently declined, the earlier effect remained embedded in standard offer prices, offering competitive suppliers an attractive opportunity to sell to Maine consumers.

Maine' migration rates can also be attributed in large part to aggregation. Aggregators in Maine have focused customers' attention on purchasing generation, educated customers about generation issues, and provided a mechanism whereby suppliers and customers may connect. The number of licensed aggregators increased from 16 in 2000 to 18 in 2001. Four active aggregators recruited large and medium customers during 2000 and expanded their recruitment to additional medium customers during 2001. Less formal groupings accomplished similar results. An additional aggregator is well along in its efforts to obtain power for its members, and two new aggregators have begun investigating generation for its members. In addition to aggregation, competitive providers directly solicited some individual large customers as well as companies with multiple branches.

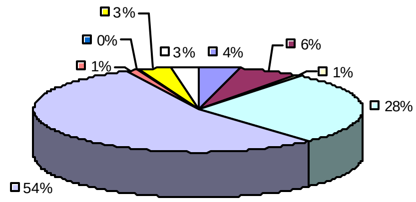
The development of a residential market has occurred only in Northern Maine, where as many as 10% of residential customers had migrated to the open market during 2001. There are a variety of reasons for the slow development of this market. Some providers assert that the standard offer price is below market price. In fact, however, the standard offer price has been set through an open market bid process. Furthermore, MPS's standard offer price of 4.29 cents in 2000 and 5.577 cents in 2001 resulted in at least some migration, but BHE's higher price of 7.3 cents in 2001 resulted in virtually no migration, suggesting that factors other than price influence market development.

Suppliers also assert that the transaction costs of obtaining a residential customer are high, and that only aggregation of a large number of customers – 5000 or more -- will make it profitable enough to attract a supplier. This assertion is consistent with the fact that there has been vigorous provider interest in residential standard offer load, where a large group of customers is guaranteed.

Finally, some suppliers have asserted that Maine's consumer protection rules are a barrier to market entry. Under these rules, many of which are statutory, providers must allow consumers a rescission period, must observe a customer verification procedure, must mail disclosure labels quarterly, and are limited in their ability to quickly end a relationship with a non-paying customer. The Commission intends to more thoroughly investigate the impact of the consumer protection rules on market activity, and report our findings to the Committee prior to the next legislative session.

During 2001, the diversity of suppliers also increased. While only three new competitive suppliers were licensed to sell electricity to consumers in 2001, the number of suppliers that sold electricity directly to customers increased by approximately a third during 2001. Most suppliers selling electricity during 2000 significantly increased their customer base during 2001. These additional sales were made through both aggregators and direct customer contact. To illustrate the pattern of non-standard offer sales, the following chart shows how sales were distributed among open market suppliers during calendar year 2000, the most recent year for which we have firm statistics.[3]

[3] Each competitive electricity provider must file an annual report describing its sales activities during the previous calendar year. The report also describes the supplier's means of complying with Maine's 30% resource portfolio requirement.



Sales in 2000, by Competitive Supplier

Another measure of restructuring's impact is the all-in cost of electricity, which is a function of both T&D utility rates and generation prices. Prices attributable to T&D rates (including stranded costs) fell when restructuring occurred and remained relatively stable throughout 2000 and 2001. Consequently, all-in price changes were driven by changes in the generation market. For residential and small commercial customers purchasing standard offer generation, all-in average prices dropped on March 1, 2000. BHE's residential and small commercial prices increased by 15% during 2001, but will lower again in March 2002 to a level comparable to the all-in pre-restructuring price, while CMP's all-in prices are still below pre-restructuring prices. Larger non-residential customers' all-in price depended upon the source of each customer's generation. The prices for larger customers receiving standard offer service increased during 2001, in some cases significantly. However, in 2000, the all-in prices for the larger customers purchasing generation from open market suppliers generally decreased to a lower level than prices to standard offer customers. While we do not know the open market generation prices for the larger customers during 2001, it is likely that customers generally retained the benefits of lower prices. In addition, the number of customers purchasing from open market suppliers doubled during 2001, so the benefit of lower retail market prices extended to those customers as well.

Following are comparisons of average prices paid by residential and small commercial customers in 2001 and after standard offer prices change in 2002. Most of these customers purchased standard offer service.

Prices for Residential and Small Commercial Customers on Standard Offer

	1999	**Current (Dec, 2001)**			**Change, 12/2001**	**March 1, 2002***			**Change, 3/2002**
	Bundled	T&D	SO	Total	vs 1999	T&D	SO	Total	vs 1999
CMP									
Residential	0.13210	0.07988	0.04089	0.12077	-8.6%	0.07988	0.04950	0.12938	-2.1%
Small Comm.	0.13400	0.08319	0.04089	0.12408	-7.4%	0.08319	0.04950	0.13269	-1.0%
BHE									
Residential	0.14510	0.09408	0.07300	0.16708	15.1%	0.09408	0.05000	0.14408	-0.7%
Small Comm.	0.13640	0.08600	0.07300	0.15900	16.6%	0.08600	0.05000	0.13600	-0.3%
MPS									
Residential	0.12697	0.07365	0.05577	0.12942	1.9%	0.07365	0.05689	0.13054	2.8%
Small Comm.	0.11973	0.07237	0.05577	0.12814	7.0%	0.07237	0.05689	0.12926	8.0%

* Does not reflect revisions to stranded cost and transmission rates.

Following are comparisons of average prices paid by medium and large customers before restructuring and during 2000, on standard offer and from open market suppliers. The prices for customers purchasing on the open market are calculated from information provided on suppliers' 2000 Annual Reports.

Prices for Customers on 3/1/2000 Standard Offer

	1999 Bundled	2000 Ave T&D	2000 Ave St.Offer	2000 Ave Total	Change 2000 vs 1999
CMP					
Medium	0.10577	0.04403	0.05990	0.10393	-1.7%
Large, Distribution Level	0.09658	0.04343	0.05335	0.09678	0.2%
Large, Transmission Level	0.05952	0.01498	0.05335	0.06833	14.8%
BHE					
Medium	0.11346	0.06036	0.05585	0.11621	2.4%
Large	0.09692	0.04998	0.05553	0.10551	8.9%
MPS					
Medium	0.09488	0.04790	0.04255	0.09045	-4.7%
Large	0.08477	0.04056	0.04004	0.08060	-4.9%

Prices for Customers in 2000 Open Market

	1999 Bundled	2000 Ave T&D	2000 Ave Generation*	2000 Ave Total	Change 2000 vs 1999
CMP					
Medium	0.10577	0.04403	0.053	0.09703	-8.3%
Large, Distribution Level	0.09658	0.04343	0.045	0.08843	-8.4%
Large, Transmission Level	0.05952	0.01498	0.045	0.05998	0.8%
BHE					
Medium	0.11346	0.06036	0.049	0.10936	-3.6%
Large	0.09692	0.04998	0.041	0.09098	-6.1%
MPS					
Medium	0.09488	0.04790	0.042	0.08990	-5.2%
Large	0.08477	0.04056	0.039	0.07956	-6.1%

* Competitive generation prices are the Commission's best estimate based on information from a variety of providers' Annual Reports.

CMP's large customer T&D rates are differentiated by voltage level, but large customer generation rates are averaged across all large customers.

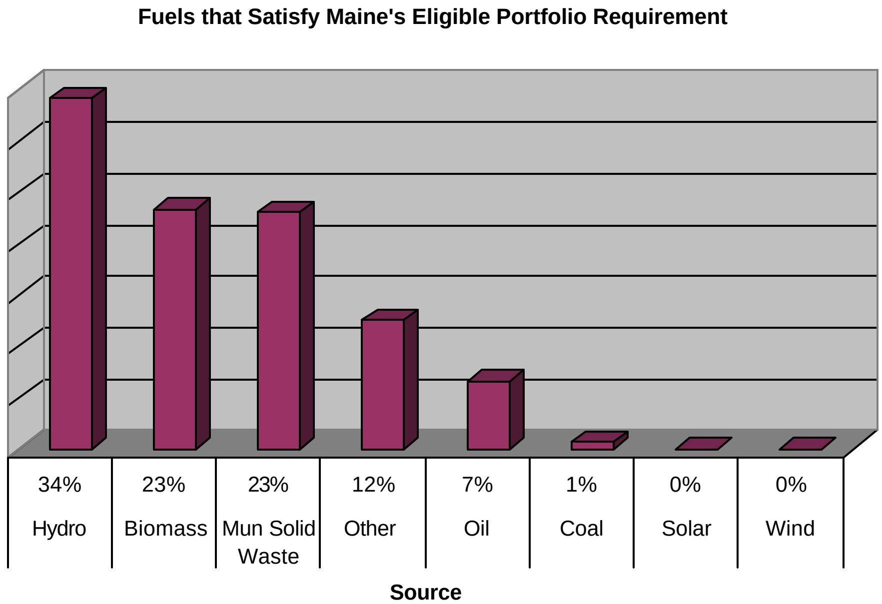
Following are comparisons of average prices paid by medium and large customers on standard offer, before restructuring and during 2001. As with the previous charts, customers generally experienced increases if they remained on standard offer service. After suppliers file their 2001 Annual Reports, we will be able to determine the extent to which customers purchasing on the open market experienced price decreases when compared with 1999 bundled rates and 2000 standard offer rates.

Prices for Customers on 2001 Standard Offer

	1999 Bundled	2000 Ave T&D	2000 Ave St.Offer	2000 Ave Total	% Change 2001 vs 1999
CMP					
Medium	0.10577	0.04451	0.08520	0.12971	22.6%
Large, Distribution Level	0.09658	0.04402	0.07946	0.12348	27.8%
Large, Transmission Level	0.05952	0.01532	0.07946	0.09478	59.3%
BHE					
Medium	0.11346	0.06036	0.07300	0.13336	17.5%
Large	0.09692	0.04998	0.07744	0.12742	31.5%
MPS					
Medium	0.09488	0.04790	0.05620	0.10410	9.7%
Large	0.08477	0.04056	0.06010	0.10066	18.8%

During 2001, the Commission considered the condition of the renewables market in Maine. One means of establishing a renewables market is through Maine's 30% portfolio requirement enacted as part of the restructuring law. Suppliers' 2000 Annual Reports and our own experience with individual suppliers confirm that suppliers are complying with the portfolio requirement. The portfolio requirement guarantees that at least 30% of generation sold in Maine is generated by "eligible" resources. Eligible resources include renewables and efficient cogeneration. In 2000, at least 38% of generation sold in Maine was generated by eligible fuels.[4] Of that amount, almost 60% was generated from traditional renewables (wood biomass and hydro), while the remainder was generated by trash or by efficient cogeneration facilities burning oil, coal, or fuels such as tires and sludge. The resources need not be located in Maine, and we estimate that approximately half of the portfolio requirement was met by out-of-state generation. The following chart show the fuels used to meet the 30% portfolio requirement in 2000.

[4] 38% understates the percentage of renewables used to serve Maine's customers because suppliers were only required to report the sources that comply with the 30% requirement.



As reported in last year's Electric Restructuring Report, we have monitored the effect of the 30% portfolio requirement on retail prices. Based on price differentials of suppliers' standard offer service bids, the requirement likely increased the cost of generation in the range of 1% to 10%, or 1 to 5 mils.

Finally, we examined why there has been no viable green product offered to residential customers. Our research, as well as many other sources, indicates that some customers would pay a premium for generation produced with environmentally benign fuel. One provider offered a green product at approximately a 1-cent premium. The product met with only minimal success and was discontinued during 2001. One aggregator attempted to offer a green product to residential and small business customers. The aggregator has received a significant level of interest among consumers, but has been unable to find a provider that would sell generation at a price the aggregator considers acceptable. We convened a group of active environmental stakeholders to explore the likelihood of additional aggregation in the near future. While interest remains in promoting renewable energy, it appears that the development of a green residential product is not imminent for the same reason that the overall residential market has not yet developed: the transaction cost of obtaining residential customers is high and the resulting margin is not as great as that available from larger customers. To the extent a residential market emerges, a green market may become more viable. In the meantime, as mentioned above, renewable resources and efficient cogeneration are supported by Maine's 30% eligible resource portfolio requirement.

III. STANDARD OFFER

A. Overview

In accordance with Maine's restructuring statute, the Commission must ensure that standard offer service is available to all customers through at least February 2005. Customers automatically receive standard offer service if they are not otherwise served by an open market supplier for whatever reason. Standard offer service is the only type of default service in Maine.

The model that Maine has followed for standard offer service, wherein standard offer prices are set to reflect the prevailing market cost of generation, is a key factor underlying the high migration statistics described earlier. Furthermore, because standard offer is "all requirements" service for which the supplier bears the load risk, it carries a cost premium that is reflected in standard offer prices. As a result, other suppliers have been able to compete against the standard offer in the larger customer sectors.

Under Maine's standard offer model, suppliers must provide service at retail except in cases where the retail bids are insufficient or unacceptable. In that case, standard offer service is provided by wholesale suppliers through contracts with the T&D utility. In either case, suppliers are chosen through a competitive bidding process in which proposals are evaluated primarily on price. The winning bid prices determine the standard offer prices that retail customers pay. If a wholesale supplier is chosen, retail prices are set to reflect both the costs of the wholesale supply and other costs that would be borne by a retail supplier, such as line losses, customer billing, and uncollectible bill expense. If a retail supplier is chosen, prices are set equal to the winning bid(s). Standard offer prices are also reset periodically, thus allowing them to follow market conditions.

In contrast, many other states have set standard offer prices administratively. For example, when retail access began in Massachusetts, standard offer prices were set at levels that were often well below market, and very little competition occurred. In addition, at those under-market prices, the Massachusetts utilities (who were providing standard offer service) accrued large cost deferrals that will have to be recovered from ratepayers in the future. In contrast, Maine's model avoids adding substantial new deferrals that may increase customers' future delivery rates.

Pennsylvania adopted a different strategy. It also set prices administratively, but at a level designed to encourage retail suppliers to compete. Indeed, it is unclear to what extent Pennsylvania's standard offer prices were actually above-market. Out-migration occurred, even in the residential sector, and Pennsylvania was considered to be a model for successful retail competition. In recent months, however, customers have returned to standard offer service as market prices have risen above standard offer prices. As shown in Appendix A, the percentage of Pennsylvania's load currently served by open market suppliers is well below Maine's.

Maine's market-based standard offer service remains key to the continued success of our retail market. Because there are risks to standard offer suppliers that are not borne by other suppliers, most notably load uncertainty, standard offer prices have been sufficiently high to allow open market suppliers to compete in the industrial and commercial sectors. This competition has not been artificially supported by imposing administratively determined "adders" on prices; rather, where open market supplier service is more efficient than standard offer service, out-migration has naturally occurred.

Finally, even in the residential and small commercial sectors where there has been little out-migration, all of these customers are served by suppliers that competed for the right to serve their loads. Thus, these customers are benefiting from competition as well.

B. Lessons Learned

The Commission has devoted substantial resources to standard offer service in the past year. We administered retail bid processes for the CMP and BHE small, medium and large classes for the term beginning March 2002. We also worked closely with CMP and BHE throughout the year as they have procured and managed wholesale power supply portfolios to serve their medium and large standard offer classes. Finally, we were involved in a contract dispute and ultimate settlement related to CMP's small class standard offer service. In this section we summarize key lessons learned from these experiences.

1. Suppliers are risk averse

This is evident in bidding strategies, as well as in concerns suppliers have articulated regarding contractual and legal issues. One illustration of risk aversion is the period of time suppliers will hold their bid prices open. In our first standard offer solicitation conducted in late 1999, bidders were required to hold prices open for a 2-month period. In our solicitation one year later, suppliers advised us that they would hold prices open for no longer than two weeks without a substantial price premium to avoid the risk that the market might move to their detriment. Although we shortened the bid period to two weeks, by the time bids were submitted, market volatility had increased to the extent that bidders would generally hold prices open for no longer than 24 hours.

With respect to contractual and legal issues, suppliers tend to prefer that their rights and obligations be well-defined, as they would be in a typical wholesale power supply contract. For example, many suppliers indicated a strong preference for a contractual legal guarantee that the Maine Legislature or the Commission would not impair their rights or change their obligations in any material way during the term of the contract. Because Maine's retail standard offer model contains no contract *per se,* we have developed alternative mechanisms to deal with these concerns. For example, in the case of the recently chosen standard offer supplier for the CMP and BHE small classes, many required protections were provided through a Commission order regarding bidder conditions and through contractual provisions with the T&D utilities. While bidders' concerns over contractual and legal issues have significantly increased the length and complexity of the procurement process, this will likely diminish as responses to bidders' issues are developed.

2. Suppliers are creative

Since the first bidding in 1999, bidders have proposed sales arrangements that are more complex than Maine's model envisioned. Thus, to operate effectively in the supply market, we have learned that we must be flexible. Our solicitation processes have evolved over time to allow flexibility and to encourage such creative bids. For example, we have allowed bids for standard offer service to be structured with contingencies, such as the acquisition of utilities' purchased power contract entitlements. In our ongoing solicitation for the CMP and BHE large classes, we have allowed bidders to propose indexed, or formula, bids. Although flexibility can make bid evaluation more difficult, it allows suppliers to put their best offers on the table and generally to mirror the creative arrangements found in competitive markets.

3. Contractual protections and financial security are critical

This lesson was soundly reinforced during the past year when a contract dispute between Energy Atlantic (EA), the CMP small class standard offer provider, and EA's wholesale supplier, Engage Energy America LLC (Engage), threatened the sustainability of the current (and quite favorable) standard offer price. Although EA had provided financial security in the form of a $33 million bond, that alone would not have fully covered the cost of replacement standard offer supply. We estimated that CMP's residential and small commercial customers were exposed to potential cost increases of as much as $150 million.

The Commission facilitated a settlement to the dispute. The settlement included payments to Engage by EA and the bond company and a reduction in Engage's entitlement costs, of which $4.5 million was funded by ratepayers. The experience, however, underscored the importance of obtaining sufficient financial security and adequate legal protections from standard offer suppliers as well as ensuring that contingent entitlement agreements cannot be unraveled by contract disputes to the ratepayers' detriment. Accordingly, the Commission will continue to retain outside legal counsel with specific expertise in this area to ensure that proper protections are included in our standard offer solicitations.

C. Standard Offer Solicitations in 2001

On July 18, 2001, the Commission decided to proceed with a standard offer solicitation for the residential and small non-residential class in the CMP and BHE territories,[5] while deferring such action for the medium and large classes. *Order Regarding Standard Offer Bid Process*, Docket No. 2001-399 (July 18, 2001). In its July 18 Order, the Commission also directed CMP and BHE to conduct a wholesale bid solicitation so that standard offer power supply could be obtained if no acceptable retail bids were received. The Commission stated that it would allow both retail and wholesale bids that are contingent on the purchase of utility entitlements at specified prices.

[5] During 2000, the Commission selected a standard offer provider for the MPS territory for a 3-year term. As a result, the Commission did not conduct a standard offer solicitation for the MPS area this year.

On July 23, 2001, the Commission issued Requests for Proposals (RFP) to provide all-requirements standard offer service for the CMP and BHE small classes. At the same time, the utilities requested bids for all-requirements wholesale service. Upon the conclusion of discussions on non-price terms with a sufficient number of bidders, we asked for final, binding bids to be presented on September 18, 2001.

After review of all the bids, the Commission concluded that a proposal by Constellation Power Source Maine (CPS Maine) to provide standard offer service on a retail basis and to have its affiliate acquire the CMP and BHE purchased power entitlements provided the most value to customers. The Commission designated CPS Maine the standard offer provider for both the CMP and BHE residential and small non-residential classes for a 3-year period beginning March 1, 2002. The prices for the 3-year period were set equal to CPS Maine's bid prices: $0.0495 per kWh for CMP customers and $0.05 per kWh for BHE customers.

In November, the Commission issued RFPs to provide all-requirements standard offer service for the CMP and BHE medium and large classes. Suppliers submitted indicative bids by December 10. The Commission is currently discussing non-price terms with bidders.

D. Standard Offer Prices Over Time

Appendix B displays standard offer prices since 1999.

E. Future of Standard Offer Service

Maine's restructuring statute requires standard offer service to be available through at least February 2005. 35-A M.R.S.A. §3212(4). The statute also requires the Commission to report to the Legislature by June 30, 2004, regarding whether and in what form standard offer service should exist after that date. At this point, we do not recommend any changes to existing statutes with respect to standard offer service, nor do we anticipate rule changes that would alter the basic structure of standard offer service in Maine prior to March 2005.

However, since the onset of restructuring, stakeholders have debated Maine's standard offer model and its implementation and have considering changes that they believe would improve its effectiveness. Some stakeholders contend that, under current procedures, there will never be a competitive retail market for small customers, as customer acquisition costs make it impossible to earn a sufficient profit at prices that will induce customers to leave the standard offer. These stakeholders argue that the Commission should set the standard offer above the bid price it accepts (with the difference used to reduce stranded costs), to the extent needed to foster competition.

The Commission supports a patient approach to the development of a competitive retail market for small customers and believes that inflating the standard offer price should be considered only if clearly necessary. As we discuss elsewhere in this report, even without a competitive retail market, small customers derive significant benefits from restructuring. The price they pay for standard offer service is the result of an increasingly competitive bid process, and the amount they pay for stranded costs will decline within a few years. In addition, it has always been assumed that a retail market for small customers would be the last to emerge, and several factors may help that to occur. As suppliers serving medium and large customers become more comfortable doing business in Maine and as those markets mature, some may look to small customers as a new business opportunity. Similarly, with the expiration of administratively set standard offer prices in other New England states, suppliers may begin serving their small customers, and the prospect of doing business regionally may encourage expansion into Maine's market.

The Commission recognizes, however, that these factors may not bring retail competition to small customers. Under the recently approved three-year standard offer, the Commission intends to monitor this situation, taking whatever steps it can to remove any non-price impediments to competition. To allow legislative consideration of the impact of Maine's standard offer laws, we intend to submit reports on standard offer service before the law requires it. We will submit a preliminary report by December 1, 2002 and a final report by December 1, 2003.

IV. STRANDED COSTS

The restructuring statute allows CMP, BHE and MPS to recover stranded costs in the rates they charge for delivery service. These stranded costs reflect net, above-market costs of generation obligations the utilities incurred prior to restructuring. For example, stranded costs include the difference between payments the utilities must make pursuant to purchased power contracts (e.g. with qualifying facilities (QFs)) and the current market value of that power. Stranded costs also include, as an offset, the proceeds from the utilities' generation asset sales (the so-called Asset Sale Gain Account, or ASGA). These proceeds are currently being amortized in rates and reduce the level of stranded costs ratepayers must pay.

Stranded cost rates were initially set for CMP, BHE and MPS effective March 1, 2000 for a 2-year period coinciding with the 2-year sale terms of the utilities' entitlements. Formal proceedings to reset stranded cost rates for the period beginning March 1, 2002 for BHE, CMP and MPS were initiated by the Commission during 2001. Major issues include: expected entitlement sales; treatment of a $20 million insurance termination disbursement received by Maine Yankee; expected revenue from special contracts; asset sale gain account amortization; and allocation of stranded costs among customer classes. We will conclude the cases for BHE and MPS in early 2002.

On December 21, we approved a stipulation that resolves the CMP stranded cost case. Under the terms of the stipulation, the stranded cost component of T&D rates will decrease for residential and small commercial customer classes. Medium and large non-residential customers currently receive a rate mitigation of 0.8 cent per kWh, funded through an amortization of the ASGA. This mitigation will cease on March 1, 2002. As a result, these customers' stranded cost rates will increase on March 1. For the largest customers receiving transmission level service, the Commission approved continuation of mitigation at a level of 0.45 cents per kWh, resulting in a smaller increase in rates for those customers.

In the sections below, we provide utility-specific stranded cost information. Amounts shown reasonably reflect the numbers currently under consideration in the pending BHE and MPS cases.

A. Central Maine Power Company

The major components of CMP's stranded costs and estimated amounts over the next three years are summarized below:

Stranded Cost Components, CMP -- $ in Millions

	Mar 02-Feb 03	Mar 03-Feb 04	Mar 04-Feb 05
QF contract costs	$252.7	$254.3	$253.9
Entitlement sale revenue*	-108.4	-102.0	-98.7
Net QF stranded costs	144.3	152.3	155.2
Closed nuclear plants	25.3	24.5	23.3
QF contract buyout	1.8	1.7	1.6
HQ tie-line	4.7	4.5	4.3
VT Yankee	0.9	1.4	1.4
Asset sale gain account	-43.4	-40.8	-38.2
Total stranded costs	**133.7**	**143.7**	**147.5**

* Based on a proxy value. The amount will be determined in early 2002.

CMP's stranded cost rates vary by rate class. The residential stranded cost rate is about 1.4 cents per kWh, which is 19% of the total T&D rate for those customers.

Stranded costs will be levelized over a three year period to maintain rate stability. CMP's ASGA will have a balance of about $125 million as of March 1, 2002 and will be amortized over four years. At the end of the four-year period, the ASGA will be gone, but remaining stranded costs will decline at that time as some QF contract terms expire.

B. Bangor Hydro-Electric Company

The major components of BHE's stranded costs and estimated amounts over the next three years are summarized below:

Stranded Cost Components, BHE -- $ in Millions

	Mar 02-Feb 03	Mar 03-Feb 04	Mar 04-Feb 05
Net purchased power costs*	$24.6	$27.9	$22.4
Ultrapower buyout payment	16.4	15.8	15.1
Beaverwood &PERC buyouts	8.8	4.6	4.1
Seabrook	3.8	3.7	3.5
Other	-4.6	-4.0	3.3
Asset sale gain account	-5.2	-8.6	0.0
Total stranded costs	**43.8**	**39.4**	**48.4**

* Based on a proxy value. The amount will be determined in early 2002.

BHE's stranded cost rates vary by rate class. The residential stranded cost rate is about 3.1 cents per kWh, which is 33% of the total T&D rate for those customers.

Stranded costs will be levelized over a period of four years to maintain rate stability. BHE's ASGA will have a balance of about $12.5 million as of March 1, 2002, and will be amortized over two years. At the end of the two-year period, the ASGA will be gone, but stranded costs will remain stable, then decline.

C. Maine Public Service Company

The major components of MPS's stranded costs and estimated amounts over the next three years are summarized below.

Stranded Cost Components, MPS -- $ in Millions

	Mar 02-Feb 03	Mar 03-Feb 04	Mar 04-Feb 05
QF contract costs	$11.3	$11.5	$11.7
Entitlement sale revenue*	-4.5	-4.1	-4.2
Net QF stranded costs	6.8	7.4	7.5
WS buydown	1.9	1.8	1.7
Seabrook	3.2	3.1	3.0
Maine Yankee	3.3	3.3	3.6
Deferred fuel	-1.3	-4.3	-4.5
Other	0.3	0.3	0.3
Asset sale gain account	-2.8	0.0	0.0
Total stranded costs	**11.5**	**11.5**	**11.5**

* Based on a proxy value. The amount will be determined in early 2002.

MPS's stranded cost rate is about 2.2 cents per kWh on average over all customers. MPS's ASGA will have a balance of about $2.8 as of March 1, 2002 and will be gone after one year. However, MPS's stranded costs will remain stable over the next decade.

V. WHOLESALE MARKET AND TRANSMISSION ISSUES

Because wholesale electric prices significantly impact the prices of Maine's retail electric consumers, the Commission participates in proceedings at the Federal Energy Regulatory Commission (FERC) and the New England Power Pool (NEPOOL). The Commission's active role in proceedings affecting New England's wholesale electric markets fulfills our statutory obligation to intervene and participate at FERC and other federal agencies to promote competition and the interests of Maine consumers and specifically to advocate for and promote the interests of Maine consumers in matters relating to the development, operations, conduct and governance of the Independent Systems Operator (ISO) and related market entities. The Commission also is guided by the Restructuring Act's finding that in order for retail competition to function effectively, the governance of the independent system operator must be "fully independent of influence by market participants." 35-A M.R.S.A. § 3215. This section of the report describes how we are fulfilling our obligations under section 3215 of Title 35-A.

A. NEPOOL

The New England Power Pool (NEPOOL) is a voluntary organization of market participants who interact with one another and with ISO New England (ISO or ISO-NE) according to a formalized set of rules embodied in the NEPOOL Agreement, the NEPOOL regional transmission tariff and the NEPOOL market rules. Maine PUC Staff regularly participates in the meetings of the NEPOOL committees that formulate the market rules, reliability requirements, and transmission tariffs. Our participation at this level enables us to hear directly from all market sectors their views on the advantages and disadvantages of the current rules or proposed amendments to those rules. If we perceive that the current rules or proposed changes threaten the ISO's independence, the market's competitiveness, or system reliability, we are able to intervene and provide informed comment at FERC consistent with our obligations under section 3215 of Title 35-A.

Although we are not market participants or members of NEPOOL, our participation on NEPOOL working committees helps us understand market issues as they evolve and anticipate how they will affect the markets. During the course of the meetings, we explain to market participants and the ISO any negative effects the proposed rules may have on Maine's ratepayers. When necessary, we request that either NEPOOL itself, or ISO New England, modify the rules to eliminate potential negative consequences for consumers. If our concerns are not addressed at this informal level, we develop formal filings to FERC, the final arbiter of all market rules. We work collaboratively with other New England states as we develop the filings to build a consensus position; whenever possible, our comments are filed jointly with the other state public utility commissions through the New England Conference of Public Utility Commissioners (NECPUC). Our collaboration with other New England public utility commissions increases the efficiency of our participation in FERC proceedings by saving money on legal fees. We also believe that presenting a unified regulatory position to FERC enhances the likelihood that our views will prevail.

We also pool staff resources with NECPUC, which has designated a Staff Energy Policy Group (SEPG) made up of staff members from each state devoted to following emerging issues and to reporting back to the commissioners and other staff members as developments occur. The group holds regular conference calls to discuss the issues as they emerge, determine which issues should receive the highest priority, and assign responsibility for monitoring any new developments.

B. ISO New England

ISO-NE serves two principal functions. It maintains the reliability of the New England power grid by coordinating the operation of the region’s 8,000 miles of transmission lines (owned by seven regulated transmission companies) and 340 generating units (most of which are owned by companies not subject to state retail rate regulation). In addition, ISO plays a central role in administering the competitive wholesale electricity market. Over the past year, the ISO has become a driver of market change through its increasingly assertive approach to market development.

We have worked hard this year to improve our communications with the ISO. Commissioners have met with members of the ISO Board of Directors and with the ISO’s market monitoring department to discuss issues regarding the competitiveness of the markets. In addition, we have participated jointly with ISONE and the Massachusetts Attorney General’s Office in an independently commissioned study of the wholesale market. Finally, NECPUC staff participates in biweekly conference calls with ISO staff, which helps NECPUC keep current on significant issues.

We also successfully supported the ISO’s efforts to preserve and enhance its independence from market participants. In several recent proceedings, FERC has stated that the ISO, rather than market participants, should propose market rules and oversee transmission planning efforts. In spite of the FERC rulings on these matters, the ISO’s independence continues to be challenged. Consistent with our legislative directive, we will continue to advocate for ISO or RTO independence from market participants because competitive markets must have efficient and impartial decision-making.

C. FERC

A third and new area driving change in the wholesale markets is the activity of FERC. Recent leadership changes at FERC have resulted in an agency that appears to be more proactive in its approach to developing the wholesale markets. As discussed below, FERC has taken a “hands-on” approach to eliminating impediments to trading across large regions, ensuring adequate capacity and reducing opportunities to exercise market power.

FERC’s enhanced activity under its new Chairman is increasing the amount and influencing the pace of the work we must do to meet our statutory obligations. Under past leadership, FERC opened up the transmission system to independent power producers with Order 888. When it perceived that it would be necessary to do more to encourage wholesale competition, FERC issued Order 2000, requiring transmission-owning utilities to form Regional Transmission Organizations (RTOs). In just this past year, FERC has twice convened large meetings to drive the RTO process, and it has directed certain geographic regions of the country to form RTOs. In addition, FERC has initiated rulemakings intended to standardize the process of interconnecting independent generators to the transmission system. The agency also initiated a rulemaking geared towards developing its own "Standard Market Design."

The increase in FERC proceedings translated to an increase in our involvement in FERC cases. A brief summary of the most important FERC proceedings and regional initiatives in which we participated is provided below. A complete listing of all the cases in which we participated is contained in Appendix C.

D. Major FERC Proceedings and Regional Initiatives

1. Standard Market Design

Early in the year, ISO-NE announced that it had decided to adopt market settlement software being used by PJM, another ISO. ISO-NE had determined that the multi-settlement and congestion management (MSS/CMS) rules that it had developed collaboratively with NEPOOL were untried and would take too long, cost too much, and engender too much risk to translate into software. ISO determined that PJM's market settlement software, which has been in use for more than two years, could be used as a base platform to support New England's markets and that it could be put into operation sooner, at lower cost and at reduced risk than a totally new software package. The two ISOs agreed to work jointly to enhance the software so it could be adapted to New England's markets and labeled this effort the "Standard Market Design" (SMD). ISO-NE approached the Maine PUC and other New England regulators seeking support for this change early in its negotiations with PJM. NECPUC agreed that the adoption of SMD offered a better prospect for getting CMS/MSS in place sooner than the original system developed jointly with NEPOOL and endorsed the ISO's SMD initiative both at NEPOOL and FERC.

The ISO projects that the new rules implementing a multi-settlement system and congestion management system will be in place early in 2003. We expect that multi-settlement system will reduce the daily volatility of electricity prices and increase market liquidity by facilitating trading with surrounding regions. The implementation of a congestion management system should reduce costs for Maine consumers because our state has an oversupply of generation and because the CMS is a prerequisite for eliminating Maine's payments for transmission congestion costs in southern New England. In 2001, these transmission congestion costs amounted to approximately $95 million for New England consumers, of which as much as $9 million were borne by Maine consumers.

2. Regional Transmission Organizations (RTOs)

The new FERC Chairman has placed much greater emphasis on the development of RTOs. FERC initiated a 45-day mediation process which it hoped would result in the development of a Northeastern RTO covering an area from northern Virginia to Maine. NECPUC participated in this proceeding by having our FERC attorney participate in the mediation discussions. We held weekly conference calls to discuss the progress of the meetings and to decide our negotiation strategy. Both NECPUC and the Maine PUC filed comments responding to the Mediators Report, which was issued at the end of the mediation process.

Subsequent to the mediated RTO discussions, FERC conducted a week long technical conference in which it invited representatives with diverse viewpoints to address technical issues having to do with RTO issues. Commissioner William Nugent represented Maine's views before FERC, and presented them with a white paper developed by the MPUC on RTO development.

3. Market Power Study

During the year 2000, New England's spot market prices and forward contract prices for power escalated dramatically. We responded to this dramatic increase by seeking an independent investigation of the New England markets. We entered into a joint effort with the Massachusetts Attorney General and the ISO[6] to retain Dr. James Bushnell of the California Energy Institute of the University of California at Berkeley to analyze the New England electricity market and to compare it to other deregulated electricity markets in the United States. Dr. Bushnell found the results of his analysis "encouraging." He found that the New England electricity markets were at least as competitive as PJM's and were significantly more efficient than the California energy market. While Dr. Bushnell found the results encouraging, he noted that continued monitoring of the markets was crucial as changes are made to ISO-NE pricing rules and operations.

4. ICAP

One of the NEPOOL markets is the Installed Capability (ICAP) market. In our last report, we indicated that Maine electricity customers had been financially hurt by recent FERC decisions and the market behavior of certain participants in the ICAP market, and we noted, somewhat hopefully, that there was some likelihood that this could be reversed. In fact, while the current ICAP market continues to be flawed, we believe it is greatly improved from a year ago. Along with others, we have been successful in making two major changes to the structure of the market. First, ICAP purchases now carry with them some protection against extremely high energy prices. ICAP plants must commit themselves to bidding no more than $1,000 per MWH ($1.00 per kilowatt-hour) which (combined with a $1,000 per MWH bid cap for all energy and reserve markets) will prevent a repeat of the $6,000 peak energy prices charged to consumers for a few hours on May

[6] The study was funded by the Massachusetts A.G. and ISO-NE. The Maine PUC was not required to contribute financially.

8, 2000. Second, the establishment of a deficiency charge which is approximately half the amount originally proposed by FERC in December 2000, as well as an increased supply of new generation, have resulted in a sharp reduction in the price for a product which now has at least some energy value. While ICAP was selling in the range of approximately $4.00 per kWh month a year ago, it is now selling for slightly less than $1.00 per kWh month, a price drop that saves Maine electricity consumers about $100 million annually.

5. Load Response Programs

In its Order directing the ISO to make improvements to ICAP, FERC acknowledged the importance of load response programs in providing discipline to competitive markets. The wholesale markets will become more competitive when consumers have the opportunity to decide in real time whether they wish to consume power at the prevailing hourly market prices. Studies have shown that a very small change in the regional load during times of system peak can have a disproportionately large effect on the market price. We are involved in several efforts to develop enhanced load response programs for the new markets. The ISO recently filed an update of its load response activities, noting that a filing extending its current program would soon be made with FERC and outlining the improvements the ISO hopes to make in these programs. We are working with the ISO and NEPOOL's Markets Committee to suggest improvements to the program. We will also participate in a separate upcoming study to examine whether changes to state retail-restructuring programs can facilitate a better demand response program at the wholesale level. Finally, NECPUC staff will review these study findings with an eye toward applying them to their own state programs.

E. NORTHERN MAINE MARKETS

Many of Northern Maine's electricity customers, as well as some generators and marketers, are not connected to the New England control area and are therefore unable to fully participate in the New England markets. Because these customers are part of the Canadian Maritimes control area and participate in a separate Northern Maine Market, they require an Independent System Administrator. The Northern Maine Independent System Administrator (NMISA) was formed in 2000 to administer the Northern Maine Market. This requires the NMISA to develop, interpret, and enforce the market rules and operating procedures and to supervise the reservation, scheduling, and dispatch of the Northern Maine Transmission system. The smaller size of the Northern Maine Market, combined with the monopoly nature of the Canadian utilities to which it is directly connected, allow the market to operate under a simpler set of rules than those in place in the rest of New England. This simplicity has resulted in relatively problem free operation in this market.

1. New Brunswick Industry Restructuring

The Province of New Brunswick has decided to open its wholesale market to competition beginning in 2003. Municipal utilities and large industrial consumers will be allowed to seek power from competitive suppliers, and existing prohibitions on the construction of independent power facilities will be eliminated. This action by the Province will influence both the New England and the Northern Maine Markets, and the Maine PUC is following the implementation of the New Brunswick energy policy. When opportunities arise, we are providing advice that will help the Northern Maine Market, the New Brunswick wholesale market, and the New England market become as closely integrated as possible.

2. East Coast Transmission Organization

Utilities in the Canadian Maritimes would like to liberalize their wholesale markets and export any excess power they may have for sale into either the Northern Maine Market or into the New England market. To do so, they must demonstrate to FERC that their market is also open and develop a Regional Transmission Organization that meets the requirements of FERC Order 2000. Canadian utilities are currently involved in discussions regarding how the organization will be structured and governed. The Maine PUC is monitoring this development and will participate in any meetings or open discussions of stakeholders. We will also intervene at FERC when appropriate.

3. Second Tie Line

The Maine Electric Power Company (MEPCO) line is the only direct electrical connection between New England and the New Brunswick Power Company (NB). The MEPCO line can transport up to 1,000 MW of power from NB into Maine, but is limited in how much power it can transport from Maine into NB. In August 2001, BHE petitioned the Commission to issue a Certificate of Public Convenience and Necessity to build a second transmission line that would allow more power to flow in both directions. In addition to a Commission proceeding, the Department of Environmental Protection will consider the environmental impact of BHE's proposal and the ISO will determine the impact of the proposal on the reliability and transfer capability of the system. As discussed later in this report, stakeholders are questioning the procedure whereby new transmission facilities are reviewed and approved in a restructured electrical system. As the first new transmission line to be considered since restructuring occurred, the BHE request will afford the Commission an opportunity to consider the appropriate approach to determining public need.

VI. LOW INCOME PROGRAM

The Restructuring Act directs the Commission to oversee the implementation of a statewide assistance program for low-income electricity customers. 35-A M.R.S.A. § 3214. On June 29, 1999, Commission staff met with stakeholders to discuss a schedule for the establishment and implementation of a statewide low-income program. The group agreed that the Commission should commence a rulemaking proceeding in 2000 to establish the design, administration, and funding criteria for a statewide program that would be implemented in the fall of 2001. The group further agreed that data must be gathered and analyzed before drafting a proposed rule and that the stakeholder group would reconvene before commencement of the rulemaking.

The Commission hired a consultant who compiled and analyzed relevant data and reported her findings and recommendations to the Commission through a report entitled "Background and Needs Analysis: Maine's Low-Income Bill Payment Assistance Programs." The Commission distributed the report to stakeholders, who reconvened to develop specific program design features.

The Commission initiated a rulemaking on February 6, 2001, to create the Statewide Assistance Plan for low-income electricity customers. In response to testimony presented at the hearing and through written comments, the Commission amended the proposed rule and issued a second proposed rule for comment on May 14. The amended rule allowed utilities with existing low-income programs to continue those programs, allowed consumer-owned utilities to develop their own low-income assistance programs (LIAPs) and included several basic design features required of all LIAPs.

On July 31, 2001, the Commission adopted the Statewide Low-Income Assistance Plan to make electric bills more affordable for qualified low-income customers. The new plan, Chapter 314 of the Commission's rules, required each of Maine's T&D utilities to create or maintain a LIAP for its customers. Chapter 314 created a central fund to finance the statewide plan and apportioned the fund to each utility based on the percentage of LIHEAP eligible persons residing in that utility's service territory.[7] Chapter 314 designated the Maine State Housing Authority (MSHA) to administer the Plan and the individual LIAPs.

Under Chapter 314, each utility contributes money to the central fund based upon the number of residential customers residing in its service territory. The funds are then redistributed to the utilities by the MSHA based upon the number of customers that are eligible for LIHEAP in each utility's service territory. In this manner, the plan ensures that each utility receives the funds necessary to address the need that exists in its service territory. In addition, the plan ensures that each utility contributes approximately the same amount per residential customer to the fund and receives the same amount per eligible person from the fund. The overall amount of the fund is approximately $5.7 million and should provide the necessary revenue to assist over 42,000 eligible customers. For the first time in Maine, every eligible person, regardless of where he or she lives, has access to an assistance program created to make electric bills more affordable.

VII. ELIGIBLE RESOURCES

A. Portfolio and Disclosure Requirements

The Restructuring Act and Commission rules promulgated to implement the Act require competitive electricity providers to serve 30% of their load from eligible resources

[7] LIHEAP is the "Low-Income Home Energy Assistance Program," which is a federally funded program that provides financial assistance grants to needy households for home energy bills and is implemented by the Maine State Housing Authority.

and to periodically disclose to customers resource mix and comparative emission information. Suppliers are required to demonstrate compliance with the portfolio and disclosure requirements in their annual reports to the Commission. Because retail access began in 2000, the first annual reports were due in April 2001.

Commission verification of compliance with the portfolio and disclosure requirements is difficult because there is currently no uniform resource tracking mechanism in New England. However, our review of the annual reports indicates that suppliers made good faith efforts to verify compliance by submitting wholesale supply contract provisions, certified statements or affidavits, or auditor statements. In addition, many suppliers outlined the generating facilities that supplied their power.

NEPOOL has been working to develop a uniform regional tracking system. This system, referred to as the Generation Information System (GIS), is expected to be in operation mid-year, 2002. After the GIS is operational, the Commission plans to reopen both the portfolio and disclosure rules to consider amendments that would take advantage of the GIS so that compliance can be more readily verified. At that time, we would also consider other improvements to the rules, such as updating comparative regional mix and emission data and removing unnecessary inconsistencies among the rules.[8]

Finally, we note that neither the portfolio nor disclosure rules were intended to provide information regarding the overall resource mix used to serve Maine consumers. In the future, we will consider requesting that suppliers inform the Commission of the resources used to serve Maine load on an annual basis so that an overall annual system mix for the State can be developed. However, it may be more productive to wait until GIS is in operation before considering whether such information should be required. As an indication of the resource mix that served a significant portion of Maine's customers, Appendix D displays the uniform disclosure labels for standard offer service provided between March 1, 2001 and the end of 2001 in Maine's investor-owned utility service territories.

B. Voluntary Renewable Resource Fund

The Restructuring Act required the Commission to establish a program to allow electricity customers to make voluntary contributions to fund renewable resource research and development and demonstration community projects. The Act specifies that the State Planning Office (SPO) will administer the program. The Commission established the program through Chapter 312 of its rules, which requires utilities to notify their customers every six months of the ability to contribute to the fund, including the option to have a specified amount added to their utility bills each month.

The results of the program to date have been disappointing. As of September 30, 2001, the utilities have collected approximately $21,000. However, the administrative costs to the utilities to obtain the contributions almost equals the total amount of contributions. Although Chapter 312 provides that utilities may recover their administrative

[8] For example, the rules treat power imported from outside the New England region inconsistently.

costs from general rates (rather then out of the contributions), the amounts in the fund have not been sufficient for SPO to fund any projects.

To identify potential means to improve the performance of the fund, the Commission sponsored several meetings attended by representatives of the Commission, the SPO, the Public Advocate's Office, the utilities and environmental groups. The meetings resulted in a plan to increase the amount of contributions, without significantly increasing the fund's administrative costs. The plan includes redrafting the utilities' solicitation materials to better promote the fund, obtaining permission of various state groups to use their logos or otherwise signal their endorsement of the fund in solicitation and promotional materials, requesting that environmental groups promote the fund to their memberships (such as through their newsletters), coordinating the next round of utility solicitations for next Spring with a joint press conference, and including more information about the fund in the Commission's consumer education materials. The Commission will keep the Legislature informed of the results of these various efforts.

VIII. CONSERVATION PROGRAM

Maine law directs the State Planning Office to develop statewide conservation programs and directs the Commission to establish conservation program expenditure levels that are consistent with SPO's program design. P.L. 1999, ch. 336. When setting delivery rates for Maine's utilities, the Commission required utilities to collect in rates an amount that is reasonable to carry out both existing conservation programs and those under consideration by SPO. In November 2001, SPO submitted its Maine Electric Energy Conservation Program Plan. The Utilities and Energy Committee is currently considering the Plan and the law that governs Maine's conservation initiatives. The Commission will wait until this consideration is complete before determining expenditure levels pursuant to statute.

IX. TRANSMISSION ISSUES

A. Annual Rate Changes

The Restructuring Act's requirement that generation be unbundled from T&D rates resulted in the transfer of jurisdiction over the transmission component of retail rates to FERC. As a result, the transmission component of retail rates is established each year through a FERC-approved formula. The transmission portion is approximately 8% to 14% of the T&D rates of CMP, BHE and MPS.

The Commission carefully reviews the utilities' annual FERC filings to ensure that the utilities have implemented the formulas correctly and that the formulas result in transmission rates that are just and reasonable. During 2001, the Commission succeeded in obtaining CMP's agreement to remove $1.8 million from its transmission rates, an amount that represented a portion of the acquisition premium from the Energy East merger. Recovery of the acquisition premium from ratepayers in this manner would have been inconsistent with the Commission's order approving the merger.

As a result of the annual FERC proceedings in 2001, increases to transmission rates caused T&D rates in CMP's territory to increase by approximately 2% on average. Because the transmission component comprises a higher portion of the delivery rate for customers receiving transmission level service, T&D rates for those customers increased by approximately 15%. In BHE's and MPS's territories, the Commission approved off-setting the small FERC-approved transmission rate increases with the asset sale gain account, resulting in no rate changes.

B. Transmission Siting

With the deregulation of generation, the Commission no longer reviews the public need for generation facilities. Thus, a Certificate of Public Convenience and Necessity is no longer required to build such a facility. Since restructuring, even the transmission line certificate proceedings have involved lines needed only to serve new generation facilities. As ratemaking issues have not been at stake for these lines, the Commission has not conducted its typical economic assessment of public need in these cases.

The lack of a "public need" analysis of generation and new transmission facilities has caused some stakeholders to suggest that a siting board or council is needed in Maine. Environmental issues are reviewed by the Department of Environmental Protection (DEP) and land use issues by local boards. Stakeholders assert that local boards are unsophisticated and ill-equipped to address state-wide land use issues and DEP's jurisdiction is limited to environmental issues. They maintain that, without an in-depth Commission review, no agency examines the "big picture." These stakeholders present valid reasons why, especially after restructuring, a Maine siting council is warranted. This issue is appropriately addressed by the Legislature.[9]

X. EXPENSES OF AFFILIATED TRANSACTIONS

The Restructuring Act requires us to assess our actual and estimated future costs of implementing the law governing the relationship between a utility and an affiliated competitive provider, and the costs to utilities of complying with those provisions. 35-A M.R.S.A. § 3217(1). 35-A M.R.S.A. § 3205 establishes the standards of conduct and marketing restrictions applicable to investor-owned utilities that market electric energy through an affiliated competitive provider. Chapter 304 of the Commission's Rules expands upon these standards.

Energy Atlantic (EA), an MPS affiliate, is the only affiliated competitive provider in the State. In addition, BHE has filed a petition for approval to form a marketing affiliate during 2002. Commission and MPS costs of enforcing affiliate standards of conduct have

[9] We note that the Legislature's Utilities and Energy Committee has considered legislation that would have created a study to investigate alternatives such as a transmission siting council. See L.D. 471 (119th Legislature 1999).

generally been minimal, consisting of periodic reports and annual audits required by Chapter 304.

However, on October 31, 2000, WPS-ESI filed a complaint against MPS alleging violations of the affiliate standards of conduct and associated Commission rule. During 2001, the Commission ordered WPS-ESI and MPS to undergo the informal dispute resolution required by Chapter 304 to resolve a portion of the WPS-ESI complaints and opened an investigation into WPS-ESI's allegation that MPS and EA have inappropriately shared employees. In the informal dispute resolution, MPS agreed to change some procedures while other allegations were deemed to be unfounded. The Commission's investigation regarding employee sharing is ongoing. These procedures have used a moderate amount of Commission resources, and MPS has incurred the cost of hiring outside counsel. However, these costs are insubstantial and are unlikely to affect customer rates or shareholder value.

XI. CONCLUSION

We continue to acknowledge and appreciate the hard work and cooperative spirit shown by the Legislature, the utilities, the suppliers, the Public Advocate and other intervenors, and our own staff as restructuring proceeds. All stakeholders continue to actively contribute useful ideas and feedback that help us determine the actions that we must take to promote a healthy competitive market. We believe that these contributions and our own attention to restructuring issues have resulted in Maine's accomplishing the most successful overall transition to competition in the nation. During 2002, we will continue or increase our participation in regional forums, monitor the continued health of the retail commercial and industrial market, and examine whether actions can be taken, consistent with Maine's open market model, to promote residential, small commercial, and renewables markets. We will continue to draw upon the expertise and experience of the stakeholders in Maine and will continue to inform the Legislature of our actions and provide recommendations when appropriate.

Appendix A
Migration Statistics from Other States

In Early 2001

	Residential	Commercial	Industrial	All Non-residential
New York	3.5%			5.4%
Maryland, statewide	2.3%			2.8%
Maryland – PEPCO	9.6%			11.9%
Massachusetts	<1%	1%	12%	
New Jersey, statewide	1.0%			8.0%
PA – PECO	18%	46%	42%	
PA – Duquesne	32%	26%	18%	
PA - other utilities	1% - 6%	6% - 40%	7% - 51%	
Rhode Island (all customers)	1.0%			
Connecticut (mid-year)	<1%	<1%		
Maine	**<1%**	**15%**	**58%**	

In Late 2001

	Residential	Commercial	Industrial	All Non-residential
New York	4.5%			25.8%
Maryland, statewide	2.7%			4.1%
Maryland – PEPCO	11.1%			17.6%
Massachusetts	<1%	4%	26%	
New Jersey	<1%			<1%
PA - PECO/1	30%	6%	5%	
PA – Duquesne	33%	10%	5%	
PA - other utilities	0% - 1%	0% - 2%	0% - 7%	
Rhode Island (all customers)	7.0%			
Connecticut (mid-year)/2	<1%	<1%		
Maine	**<1%**	**39%**	**87%**	

1/ Approximately half this migration was residential customers who made no choice, but were assigned to PECO.
2/ Connecticut migration is influenced by a green product.

Appendix B
Summary of Standard Offer Prices and Supply Source

CMP Standard Offer Prices March 2000 – December 2000

	Non-Summer (¢/kWh)	Summer (¢/kWh)
Residential/Small Commercial	4.089	4.089
Medium Class	5.52	6.81
Large Class		
On-Peak	5.925	11.041
Off-Peak	3.3783	3.8823

Energy Atlantic served the residential/small commercial class for two years. CMP entered into a fixed contract to serve all requirements except ICAP of the medium and large classes. CMP purchased ICAP on the open market as needed throughout the year.

CMP Standard Offer Prices in January 2001 - February 2001

	Non-Summer (¢/kWh)
Residential/Small Commercial	4.089
Medium Class	6.4
Large Class	
On-Peak	6.6327
Off-Peak	4.0860

Increased to recover actual ICAP cost in Jan and Feb, after FERC increased ICAP rate to $8.75 retroactive to Aug. Retroactive and potential additional future ICAP costs were not recovered through the increase.

CMP Standard Offer Prices in March 2001 - February 2002

	Non-Summer (¢/kWh)	Summer (¢/kWh)
Residential/Small Commercial	4.089	4.089
Medium Class	8.52	8.52
Large Class		
On-Peak	8.971	14.576
Off-Peak	5.596	6.543

CMP entered into a fixed contract to serve all requirements of the medium class and a 2nd contract to supply all requirements except ICAP of the large class. CMP will purchase ICAP on the open market as needed for the large class throughout the year.

CMP Standard Offer Prices in March 2002 - February 2005

	Non-Summer (¢/kWh)	Summer (¢/kWh)
Residential/Small Commercial	4.95	4.95
Medium Class	Bid process under way	Bid process under way
Large Class	Bid process under way	Bid process under way

Constellation Power Source Maine will supply standard offer service to residential and small commercial customers for three years.

Appendix B (Continued)

BHE Standard Offer Prices on March 1, 2000

	Non-Summer (¢/kWh)	Summer (¢/kWh)
Residential/Small Commercial	4.5	4.5
Medium Class	4.624	5.704
Large Class		
On-Peak	5.314	7.459
Shoulder	4.680	6.829
Off-Peak	3.848	4.117

BHE entered into a fixed contract for 60% of requirements for all classes, purchased 40% on the spot market, and entered into 3 fixed contracts to protect against high summer energy prices.

BHE Standard Offer Prices August 2000 – February 2001

	August	September (non-summer)	Oct – Feb (non-summer)
Residential/Small Commercial	4.608	4.608	6.106
Medium Class	6.127	4.967	6.127
Large Class			
On-Peak	7.982	5.687	7.041
Shoulder	7.308	5.008	6.201
Off-Peak	4.406	4.118	5.100

Increased Aug 1 to recover $1M in actual costs incurred through the 3 additional fixed contracts. Medium and large customers would pay their allocation during Aug & Sept. Other customers would pay during Aug through Feb. Increased Oct 1 to recover additional increases in energy spot market in September and a clerical error regarding under-collection by the 3 additional fixed price contracts.

BHE Standard Offer Prices on March 1, 2001 – February 2002

	Non-Summer (¢/kWh)	Summer (¢/kWh)
Residential/Small Commercial	7.3	7.3
Medium Class	6.889	8.498
Large Class		
On-Peak	9.292	9.292
Shoulder	7.565	7.565
Off-Peak	6.964	6.964

BHE entered into a 6-month and a 3-year contract to serve an estimated 80%, 60% and 40% (respectively) of energy requirements of the small & medium classes. The price levelizes the 3 years' costs, allowing a lower rate in year 1. BHE entered into a contract to serve all requirements, except uplift and load above 65MW, of the large class. ICAP, uplift, and the remaining energy for the small and medium classes were obtained on the open market. Undercollection from the previous year will be collected in 2001.

BHE Standard Offer Prices on March 1, 2002 – February 2005

	Non-Summer (¢/kWh)	Summer (¢/kWh)
Residential/Small Commercial	5.0	5.0
Medium Class	Bid process under way	Bid process under way
Large Class	Bid process under way	Bid process under way

Constellation Power Source Maine will provide standard offer service to residential and small commercial customers for three years.

Appendix B (Continued)

MPS Standard Offer Prices March 2000 – February 2001

	¢/kWh
Residential/Small Commercial	4.2906
Medium Class	4.2549
Large Class	4.0038

* WPS-ESI served the residential/small commercial and large class and 80% of the medium class. Energy Atlantic served 20% of the medium class.

MPS Standard Offer Prices in March 2001 - February 2002

	¢/kWh
Residential/Small Commercial	5.577
Medium Class	5.62
Large Class	6.01

* WPS-ESI will serve all classes for 3 years.

MPS Standard Offer Prices March 2002 – February 2003

	¢/kWh
Residential/Small Commercial	5.689
Medium Class	5.732
Large Class	6.13

MPS Standard Offer Prices March 2003 – February 2004

	¢/kWh
Residential/Small Commercial	5.802
Medium Class	5.847
Large Class	6.253

Appendix C
Public Utilities Commission or NECPUC Intervention at FERC

Following are major FERC proceedings in which the Maine Public Utilities Commission (MPUC) participated during 2001:

ICAP CASES

APS Complaint (ICAP clearing prices for April –July)

In 1999, the average price in the ICAP auction market was $ 0.17. In January through March the ISO mitigated to zero ICAP bids which it found resulted from exercises of market power. This bid mitigation resulted in a clearing price of zero for those months. The ICAP auction price for April cleared at $3.25 per KW-month. The preliminary clearing prices for subsequent months were even higher. The Maine Commissioners sent a letter to Philip Pellegrino, CEO of the ISO, asking the ISO to investigate these prices and to consider mitigation of bids for May through July. APS filed a complaint requesting that the FERC direct the ISO to investigate ICAP bidding patterns for March through July 2000. The MPUC supported APS's complaint. The ISO did not clear ICAP for May through July as it had been planning to do. Instead it asked the FERC for guidance on what it should do.

APS Complaint, Motion for Disclosure

In the MPUC's letter to the ISO about the April ICAP clearing price and preliminary prices for subsequent months, the MPUC asked for bid stacks to examine the bidding patterns of players in the ICAP market. The ISO was going to provide the information but when it received complaints from companies owning generation, who argued that the NEPOOL Information Policy did not allow ISO to provide us with the information, it asked us to ask the FERC for the information. On November 13, 2000, the MPUC filed a motion for disclosure asking that the information be made public, that in general bid data be released after 3 months and that the FERC clarify that the NEPOOL Information Policy allows the ISO to provide the confidential market information in its possession to state regulators if the requesting regulators issue a protective order to keep the information confidential. NECPUC later filed an answer in support of the ISO's motion. This information is crucial to state regulators' ability to determine whether the wholesale markets are becoming workably competitive and whether additional changes to market structures are necessary. The information is now publicly released after six months.

APS Complaint, Northeast Utilities Proposal

On October 19, 2001, Northeast Utilities and its affiliates requested that the FERC resolve APS's ICAP complaint and related complaints about the ISO's ICAP-related mitigation actions by imposing the $4.87 deficiency charge approved by the FERC on August 28, 2001 as a component of the ISO's interim ICAP product as the "mitigation price" for the months of January through July 2000. The MPUC and numerous other parties opposed the retroactive imposition of the $4.87 deficiency charge as a "mitigation price" in the auction market.

All of the pleadings in this docket are still pending.

Related ICAP cases in Docket No. EL00-62 (key orders and filings)

June 28, 2000 FERC Order eliminating the ICAP market and requiring ISO to develop a deficiency charge

August 28, 2000 ISO filed a deficiency charge of 0.17 based on an average of clearing prices in the ICAP auction market. The filing was supported by the NEPOOL participants committee. NECPUC filed comments in support of the 0.17 deficiency charge.

December 15, 2000 The FERC rejected the ISO's proposed deficiency charge and ordered the imposition of an $8.75 deficiency charge to be imposed retroactively to August 1, 2000.

December 22, 2000 The MPUC filed an Emergency Motion for Stay and Request for Rehearing. Numerous other entities also filed motions for stay and requests for rehearing.

January 10, 2001 The FERC granted the motions for stay until 30 days after the issuance of an order on rehearing of the December 15, 2000 order. Dissent by then Chairman Hebert.

January 16, 2001 The MPUC filed an amendment to its request for rehearing, in which its supplied data on the bilateral markets in response to Chairman Hebert's dissent.

March 6, 2001 The FERC issued its Order on Rehearing in which it (1) granted rehearing of its earlier decision to impose the $8.75 charge retroactively (2) affirmed its earlier decision setting the deficiency charge at $8.75 a kW month for April 1, 2001 and thereafter.

March 16, 2001 The MPUC, Bangor Hydro-Electric Company and Central Maine Power Company and other entities filed a Motion in the Federal Court of Appeals for the First Circuit, to stay the FERC decision.

March 30, 2001 The Federal Court granted a stay which prevented the FERC from imposing the $8.75 charge until the further order of the court but allowing it to impose the $0.17 ICAP deficiency charge.

March 30. 2001 The FERC imposed the $0.17 deficiency charge pending further review of the court.

June 4, 2001 ISO filed a compliance filing in accordance with the FERC's March 6 order proposing a new interim ICAP product with a deficiency charge of $4.87. The proposal also provided a very limited opportunity to cure deficiencies after the end of the month.

June 8, 2001 The federal court remanded the case to the FERC requiring it to give more reasoned explanation of its decision.

August 28, 2001 The FERC accepted the ISO's interim ICAP filing in part but rejected the ISO's requirement for a participant to purchase 95% of its ICAP obligation before the start of the month. The requirement was rejected because it would require participants to guess the amount of their ICAP obligation and would penalize those participants if they guessed incorrectly. Several ICAP suppliers filed motions for clarification seeking a clarification that the Commission intended to require a 100% advance purchase requirement. The MPUC opposed these motions.

September 27, 2001 ISO filed a compliance filing in which it eliminated the advance purchase requirement.

September 28, 2001 The FERC issued its order on remand from the federal court in which it found that no further action was required because of its recent adoption of an alternate deficiency charge

November 20, 2001 The FERC issued an Order on Rehearing in which it required the ISO to develop methodology to determine participants ICAP obligation in advance

December 20, 2001 The MPUC and others filed motions for rehearing of the FERC's November 20, 2001 order.

INTERIM BID CAPS

On September 20, 2001, ISO-NE submitted a proposal to extend the Interim Bid Cap of $1000 per MWh to all markets until October 31, 2002. Both MPUC and NECPUC filed comments in support of the proposed extension. On October 25, 2001, the FERC granted the extension of the interim bid caps to all markets until the Northeast RTO is operational.

MAY 8TH COMPLAINT

On August 17, 2000, the MPUC filed a complaint seeking a recalculation of the $6000 MWh clearing price for several hours on May 8, 2000. As a result of the price spike, BHE paid approximately $2.6 million for energy for five hours on May 8th. The MPUC also filed an answer responding to the numerous generator protests to the Complaint. On December 20, 2001 FERC denied the Complaint filed by the MPUC and related complaints filed by BHE and United Illuminating Company. The MPUC is considering whether to file a request for rehearing.

STANDARD MARKET DESIGN

In March of 2001, the ISO notified the FERC that it sought to implement the congestion management system and multisettlement system already in place in the PJM control area. ISO determined that by adopting the PJM market rules as a Standard Market

Design for the New England control area, it could implement CMS/MSS much more quickly and at considerable savings to participants. While many in NEPOOL supported the adoption of a standard market design, several factions challenged the ISO's authority to propose new rules adopting the SMD. NECPUC supported the ISO's adoption of SMD and also supported its authority to propose market rules adopting the standard market design. The FERC initially dismissed the ISO's SMD filing because it thought that a standard market design could be quickly adopted as part of the RTO mediation process. The ISO, the MPUC and others filed requests for rehearing of the Commission's order which would have had the effect of indefinitely delaying the adoption of CMS/MSS in New England. On September 17, 2001, the FERC changed course and allowed the ISO to continue developing the SMD.

RTO

NECPUC developed its own Regional Transmission Organization (RTO) proposal that promoted the concept of an independent oversight board and in February 2001 filed this proposal in response to the NERTO proposal filed by the ISO and the transmission owners. NECPUC's proposed regional markets board would oversee the operation of the NE markets and would include a market monitoring and mitigation unit. The MPUC supported this proposal but sought more of a role for the board in transmission expansion planning and approval. In an order issued on July 12, 2001, the FERC directed participants in the New England, New York and PJM RTO proceedings to participate in mediation on forming a single Northeast RTO. The MPUC determined not to participate individually in the mediation sessions, but NECPUC counsel participated in the discussions. The mediation produced only a list of issues that the FERC needs to resolve in moving forward with a Northeast RTO. The mediator provided his own opinions and recommendations on issues such as representation on the RTO board and timetables for implementation. The MPUC filed comments on the mediator's report and also sent the FERC commissioners a white paper outlining the MPUC's ideas for creating northeast wholesale electricity markets. The FERC has recently indicated that it will engage in a rulemaking to determine standards for implementing RTOS.

OTHER SIGNIFICANT CASES

External Contracts

On July 10, 2001, the ISO proposed a change in market rules that would prevent external contracts from setting the clearing price. The ISO argued that external contracts should not set the clearing price because of their inability to respond within short intervals of time to dispatch instructions. Because of this inflexibility, external contracts often cause an upward distortion to the clearing price. Both MPUC and NECPUC supported ISO's proposal. In its September 7, 2001 Order, the FERC approved the ISO's proposal to prevent Emergency Energy Transactions (EETs) from setting the clearing price but was concerned that not all external contracts were inflexible. Thus, it found that preventing all external contracts from setting the clearing price was too broad a remedy. In compliance, the ISO filed rate sheets that prevented only non-dispatchable external contracts and EETs from setting the clearing price. However in response to motions for clarification and a complaint filed by a participant, the FERC subsequently clarified that EETs are the only external contracts that are prevented from setting the clearing price, but that the ISO could make a new filing proposing that only non-dispatchable external contracts would be barred from setting the clearing price. The ISO is considering whether to make this filing.

Bangor Hydro Complaint

On June 15, 2001, BHE filed a complaint against the ISO asking the FERC to correct the erroneous clearing prices that resulted from the failure of ISO's electronic dispatch software from dispatching units in a manner consistent with the market rules. As a result of these errors, BHE alleged that it and its customers paid approximately one million dollars more than it would have paid if the software were operating correctly. The MPUC filed comments in support of BHE's complaint noting that the FERC had the authority and obligation to correct these clearing prices because they were calculated in a manner inconsistent with the filed rate. On December 20, 2001, the FERC denied the Complaint finding that the prices were calculated in accordance with the filed rate. The MPUC is considering whether to request rehearing of this decision.

Compliance Filing, MSS/CMS

NEPOOL was required by the terms of the June 28, 2000, MSS/CMS Order to make compliance filings relating to transmission planning. The MPUC protested certain aspects of the filing, which did not comply with the requirement that transmission owners should not have a decisional role in transmission planning and which continued indefinitely the socialization of costs for transmission upgrades when the parties were unable to agree on what entity should pay these costs. On June 13, 2001, the FERC found that NEPOOL's compliance filing as it related to transmission planning did not comply with the June 28, 2000 MSS/CMS Order because it continued to give transmission owners a decisional role in transmission planning. The FERC emphasized that the ISO should have exclusive responsibility for transmission planning. Further, the FERC directed the ISO to revise its authority under its interim agreement with NEPOOL to state that "the ISO shall have sole responsibility to develop such new System Rules and Procedures as may be necessary to allow the ISO to carry out its obligations under this agreement. " 95 FERC ¶ 61,384 at 62,438 (2001). NEPOOL sought to clarify that the order granted the ISO the exclusive right to file only those market rules relating to transmission planning. The MPUC contested this effort to narrow the effect of FERC's ruling. In an Order issued on August 27, 2001, the FERC denied NEPOOL's request for clarification and made clear that that FERC intended that ISO rather than NEPOOL should have authority for proposing all market rules, not simply those related to transmission planning. The FERC also denied a request for rehearing of its decision to continue socializing congestion costs until the implementation of CMS.

MR 5 Rule Change aimed at reducing energy uplift.

The MPUC filed comments supporting a compliance filing to address FERC's reason for rejecting changes to market rule 5 aimed at reducing energy uplift. The compliance filing proposed the same changes but added language to address FERC's concern.

The FERC accepted the compliance filing. The revised MR5 should significantly reduce energy uplift.

Consumers of New England Complaint

This complaint proposes several changes to the decision making process at NEPOOL. NECPUC filed comments supporting the complaint as a first step toward reducing gridlock at NEPOOL but reiterated its long- term concerns about the current governance structure and the need for an independent regional markets board. This complaint is pending

Appendix D
Uniform Disclosure Labels for Standard Offer Service

The following pages contain the most recent uniform disclosure labels for standard offer service BHE, CMP and MPS service territories.

Appendix D (Continued)

UNIFORM INFORMATION DISCLOSURE LABEL

for

Standard Offer Service provided by Energy Atlantic, LLC

(Meets or Exceeds Maine's 30% Renewable Requirement)

Residential & Small Commercial Class
November 2001

Generation Price:

Average price per kWh at different levels of use. Prices do not include regulated charges for customer service and delivery:

Ave. Use per Month	250 kWh	500 kWh	1000 kWh	2000 kWh	10,000 kWh	20,000 kWh	40,000 kWh
Ave. Price per kWh	4.089 ¢	4.089 ¢	4.089 ¢	4.089 ¢	4.089 ¢	4.089 ¢	4.089 ¢

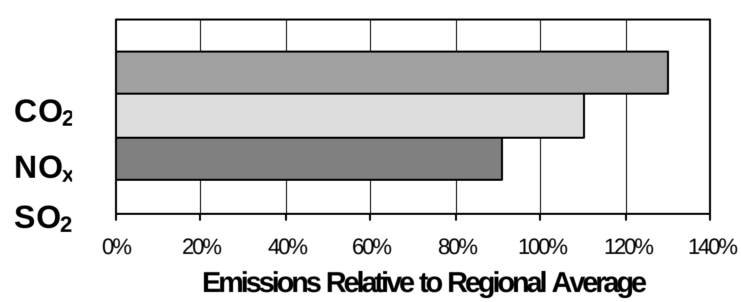
Power Sources:

Demand for this electricity product was assigned generation from the following sources:

Biomass	14 %
Coal	13 %
Hydro	9 %
Nuclear	15 %
Natural Gas	13 %
Solar	0 %
Oil	26 %
Other Renewables	7 %
Wind	0 %
Municipal Trash	3 %

Air Emissions:

Carbon dioxide (CO_2), nitrogen oxide (NO_x), and sulphur dioxide (SO_2) emission rates from these sources, relative to the regional average:



Appendix D (Continued)

UNIFORM INFORMATION DISCLOSURE LABEL

for

Standard Offer Service provided by Central Maine Power Company

(Meets or Exceeds Maine's 30% Renewable Requirement)

Medium Non-Residential Class
October 2001

Generation Price: Standard Offer price in effect Mar 1, 2001- Feb 28, 2002 is 8.520 ¢ per kWh

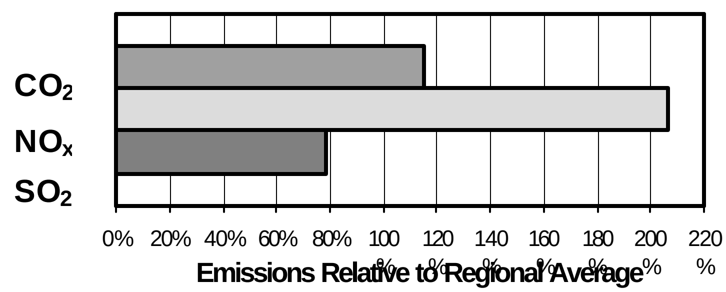
Power Sources:

Demand for this electricity product was assigned generation from the following sources:

Biomass	1 %
Coal	13%
Hydro	5 %
Nuclear	15%
Natural Gas	13 %
Solar	0 %
Oil	21 %
Other Renewables	0 %
Wind	0 %
Municipal Trash	32 %

Air Emissions:

Carbon dioxide (CO_2), nitrogen oxide (NO_x), and sulfur dioxide (SO_2) emission rates from these sources, relative to the regional average:



Appendix D (Continued)

UNIFORM INFORMATION DISCLOSURE LABEL

for

Standard Offer Service provided by Central Maine Power Company

(Meets or Exceeds Maine's 30% Renewable Requirement)

Large Non-Residential
August 2001

Generation Price: Standard Offer prices in effect Mar 1, 2001- Feb 28, 2002

Peak Usage Season (June-Aug)		Non-Peak Usage Season (Sept-May)	
On-peak	**$0.14576**	**On-Peak**	**$0.08971**
Interim	**$0.14576**	**Interim**	**$0.08971**
Off-Peak	**$0.06543**	**Off-Peak**	**$0.05596**

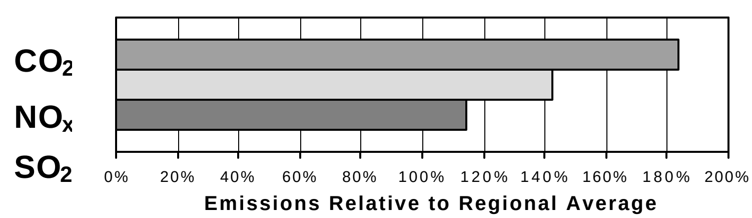
Power Sources:

Demand for this electricity product was assigned generation from the following sources:

Biomass	0 %
Coal	70 %
Hydro	30 %
Nuclear	0 %
Natural Gas	0 %
Solar	0 %
Oil	0 %
Other Renewables	0 %
Wind	0 %
Municipal Trash	0 %

Air Emissions:

Carbon dioxide (CO_2), nitrogen oxide (NO_x), and sulfur dioxide (SO_2) emission rates from these sources, relative to the regional average:



Uniform Disclosure Information Label

Electricity Facts

For Residential and Small Non-Residential Customers of Standard Offer Service within Maine Public Service Company's Service Territory

December 2001

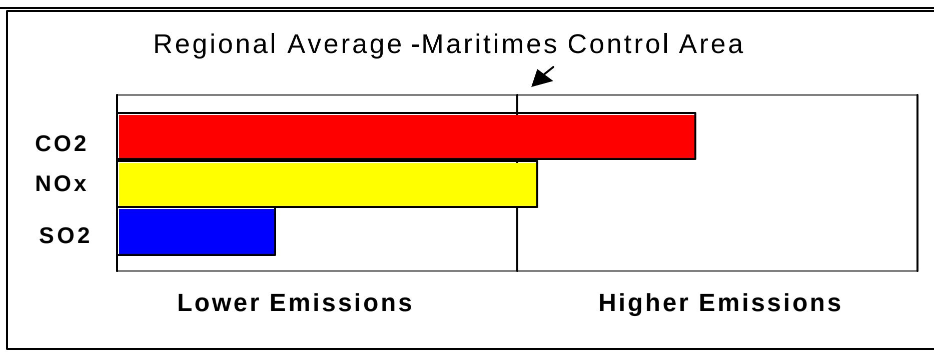
Generation Price – Average Price per KWH					
Average price per KWh at different levels of use. Prices do not include regulated charges for customer service and delivery.	Average Use per Month	**250 KWh**	**500 KWh**	**1,000 KWh**	**2,000 KWh**
	Residential	**5.577 Cents**	**5.577 Cents**	**5.577 Cents**	**5.577 Cents**
	Average Use per Month	**1,000 KWh**	**10,000 KWh**	**20,000 KWh**	**40,000 KWh**
	Small Commercial	**5.577 Cents**	**5.577 Cents**	**5.577 Cents**	**5.577 Cents**
	Your average generation price may vary according to when and how much electricity you consume. See your most recent bill for your monthly use.				

Contract	The prices and terms of **Standard Offer Service** are regulated by the **Maine Public Utilities Commission.** The above generation prices are scheduled to remain in effect until March 1, 2002. **WPS Energy Services** is the current provider for customers taking Standard Offer Service.

Power Sources				
This Electricity product was assigned generation from the following sources.	**Power Sources**	**%**	**Power Sources**	**%**
	Biomass	53	Coal	8
	Hydro	19	Nuclear	8
	Natural Gas	0	Solar	0
	Oil	12	Other Renewables	0
	Wind	0	Municipal	0

Air Emissions

Carbon dioxide (CO2), nitrogen oxide (NOx), and sulfur dioxide (SO2) emission rates from these sources relative to the regional average.



Notes
1. The power source and air emissions information is based on 12 months of historical data.
2. See reverse side for further information.
3. You may also call WPS Energy Services at 1-877-838-0454 or the Maine Public Utilities Commission at 1-877-782-3228 for more information regarding these facts.

Appendix D (Continued)

Appendix D (Continued)

The following description, or a variation thereof, appeared on each disclosure label.

Label Descriptions

Generation Price: Generation prices are shown at usage levels that are typical for residential and commercial customers.

Power Sources: The actual electricity you use will be indistinguishable from the electricity used by your friends and neighbors. This is unavoidable because everyone is served through the same transmission and distribution system. The power sources label cannot tell you about source of the electricity that you use in you home or business; instead, it tells you that your dollars are going to pay for particular power plants. Since it is impossible to track the flow of electricity on the grid, however, there is no way to identify the actual power plant that produced the electricity you consume. But it is possible to track the dollars you pay to particular power plants. Your electricity dollars will support electricity generation from various energy resources in the proportions listed on the power content label.

Emissions: Emissions for each of the following pollutants are presented as a percent of the regional average emission rate.

Carbon Dioxide (CO_2) is released when certain fuels are burned. It is considered a major greenhouse gas and a major contributor to global warming.

Nitrogen Oxides (NO_x) form when certain fuels are burned at high temperatures. They are considered contributors to acid rain and ground-level ozone (or smog).

Sulfur Dioxide (SO_2) is formed when fuels containing sulfur are burned. Major health effects associated with SO_2 include asthma, respiratory illness and aggravation of existing cardiovascular disease.

The production of electricity can produce harmful emissions and have other environmental impacts. Environmental impacts differ among different power plants.